STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

F I L E D
08-15-07
04:01 PM

August 15, 2007

Agenda ID #6908
Quasi-legislative

TO PARTIES OF RECORD IN RULEMAKING 06-04-009

This is the proposed decision of Commissioner Michael R. Peevey. It will appear on the Commission's September 6, 2007 agenda. The Commission may act then, or it may postpone action until later.

When the Commission acts on the proposed decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Pursuant to Rule 14.6, comments on the proposed decision must be filed within 9 days of its mailing. Comments are due no later than August 24, 2007, and reply comments no later than August 30, 2007.

Comments must be filed either electronically pursuant to Resolution ALJ-188 or with the Commission's Docket Office. Comments should be served on parties to this proceeding in accordance with Rules 1.9 and 1.10. Electronic and hard copies of comments should be sent to ALJ Charlotte TerKeurst at cft@cpuc.ca.gov and the assigned Commissioner. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/s/ ANGELA K. MINKIN
Angela K. Minkin, Chief
Administrative Law Judge

ANG:rbg

Attachment

Decision **PROPOSED DECISION OF COMMISSIONER PEEVEY**
(Mailed 8/15/2007)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies.	Rulemaking 06-04-009 (Filed April 13, 2006)

(See Attachment C for List of Appearances.)

INTERIM OPINION ON REPORTING AND TRACKING OF GREENHOUSE GAS EMISSIONS IN THE ELECTRICITY SECTOR

TABLE OF CONTENTS

Title Page

TABLE OF CONTENTS

Title Page

INTERIM OPINION ON REPORTING AND TRACKING OF GREENHOUSE GAS EMISSIONS IN THE ELECTRICITY SECTOR

I. Summary

The California Public Utilities Commission (Public Utilities Commission) and the California Energy Commission (Energy Commission) recommend that the California Air Resources Board (ARB) adopt the proposed rules contained in Attachment A to this order, as reporting and tracking requirements applicable to retail providers and marketers in the electricity sector. These requirements would be adopted as part of ARB's implementation of Assembly Bill (AB) 32, which requires that statewide greenhouse gas (GHG) emissions be reduced to 1990 levels by 2020.

The proposed electricity sector reporting and tracking protocol (Protocol) in Attachment A that we recommend to ARB would apply to all retail electricity providers in California, including investor-owned utilities (IOUs), multi-jurisdictional utilities, electric cooperatives, publicly-owned utilities (POUs), energy service providers (ESPs), and community choice aggregators (CCAs). Because the Western Area Power Administration (WAPA) sells a small amount of power to end users in California, it is a retail provider and, thus, would be required to report under the recommended Protocol. Similarly, the California Department of Water Resources (DWR), and any other state agencies that generate or procure power, would be required to report the power that they generate or procure to serve their own loads. Separate reporting requirements in Attachment A would apply to marketers that import power into or export power from California. The annual reports submitted in compliance with the

recommended reporting Protocol would complement the electricity source-based reporting requirements that are being developed separately by ARB.

The Public Utilities Commission and the Energy Commission have developed the recommended reporting Protocol to collect the information that would be needed to track GHG emissions attributed to the electricity sector under a load-based GHG regulatory approach. In addition, the Protocol provides for the collection of information from marketers that would be needed if a GHG regulatory approach that focuses on entities that deliver power to the California transmission grid (sometimes called a "deliverer" or "first-seller" approach) is adopted instead of a load-based approach.

AB 32 requires that regulations adopted by ARB ensure that identified GHG emission reductions are "real, permanent, quantifiable, verifiable, and enforceable" by ARB. (Section 38562(d)(1).)[1] To that end, Attachment A contains certain recommendations regarding the manner in which GHG emissions occurring due to owned power plants, purchases from specified sources, and wholesale sales are attributed to retail providers.

Attachment A contains several other recommendations regarding reporting and tracking, including the treatment of null power from renewable resources and the manner in which GHG emission factors should be determined when the source of a power purchase is not identified. We recommend that ARB adopt the default emission factors contained in Table 1, for use in attributing GHG emissions to retail providers due to their operations in 2008.

---

[1] Unless indicated otherwise, citations to Sections refer to California Health and Safety Code sections added by AB 32.

Table 1

Recommended Default Emission Factors

Type of Power	Default Emission Factor*
California Independent System Operator (CAISO) real-time and Integrated Forward Market purchases	1,000
Purchases from other in-state unspecified sources	1,000
Purchases from Pacific Northwest unspecified sources	714
Purchases from Southwest unspecified sources	1,075

* Measured in pounds of carbon dioxide equivalent emissions per megawatt-hour (lbs CO_2e/MWh).

The recommendations we adopt today apply to the reporting and tracking of GHG emissions during 2008. Modifications may be warranted for future years once the type of GHG regulation for the electricity sector is determined. We recommend additionally that a comprehensive review of GHG reporting requirements for the electricity sector be undertaken in 2010, so that updated reporting requirements can be in place prior to the commencement of the GHG regulatory scheme in 2012.

We support the call made by several parties in this proceeding for a multi-state regional GHG reporting and tracking system. A regional solution to reporting and tracking would greatly increase the accuracy of GHG reporting in

California. We urge ARB to lead a regional effort to develop and implement such a system.

II. Background

AB 32 requires that, on or before January 1, 2008, ARB adopt regulations to require the reporting and verification of statewide GHG emissions and to monitor and enforce compliance with the program. (Section 38530(a).) The statute specifies that "statewide GHG emissions" includes the total annual emissions of GHG gases in the state. (Section 38505(m).) While certain language in AB 32 focuses on "electricity consumed in the state," we interpret the statutory definition of "statewide GHG emissions" to include emissions from electricity generated in California and exported from the state, in addition to electricity consumed in the state.

Decision (D.) 07-05-059, the second order amending the Order Instituting Rulemaking (R.) 06-04-009, and the Scoping Memo for Phase 2 of this proceeding provide that the Public Utilities Commission, in collaboration with the Energy Commission, will provide recommendations to ARB regarding, among other things, the reporting and tracking regulations that ARB will adopt pursuant to AB 32.

The Public Utilities Commission and the Energy Commission jointly held a workshop on April 12 and 13, 2007 that addressed GHG reporting and tracking issues, among other subjects. Based on information presented at that workshop, subsequent ARB workshops, and existing reporting protocols of the Energy Commission and the California Climate Action Registry, staff from the two agencies (Joint Staff or Staff) developed a Joint Staff proposal for an electricity retail provider GHG reporting protocol. Pursuant to a June 12, 2007 ruling by the Administrative Law Judges (ALJs), parties were allowed to comment on the

Joint Staff proposal. The ALJ ruling also invited parties to comment, among other things, on whether modifications to the Joint Staff reporting proposal would be needed to support a deliverer/first-seller GHG regulatory structure for the electricity sector.

Today's decision is based on information presented at the April 12 and 13, workshop; the Joint Staff reporting proposal; materials incorporated into the record by ALJ rulings dated June 18, June 27, and July 19, 2007; and comments filed by the parties in this proceeding.

III. Overview of Tracking of GHG Emissions in the Electricity Sector under a Load-based Regulatory System

This section provides a general description of the method that we recommend to ARB for tracking GHG emissions in the electricity sector if a load-based regulatory approach is adopted for the electricity sector. Subsequent sections address the needed reporting and tracking provisions in more detail.

ARB plans to collect net generation, fuel consumption, and GHG emissions data from all generating facilities in California with a nameplate generation capacity of one or more megawatts (MW). The reporting and tracking protocol we recommend for the electricity sector would complement ARB's source-based protocol.

The load-based tracking approach in Attachment A would assign responsibility to each electricity retail provider for the GHG emissions associated with the electricity generated to serve its load. Consistent with this approach, the retail providers would report information regarding their procurement of electricity from various types of sources, including the following:

- o Owned generation, which includes partial ownership (in-state or out-of-state),

- Power purchase agreements (PPAs) tied to specific power plants,
- PPAs tied to specific fleets of power plants,
- PPAs that do not specify the generation source(s), and
- Purchases from the CAISO's real-time market and the planned Integrated Forward Market.

ARB would then attribute GHG emissions to the power procured by the retail provider, based on emissions information from a variety of sources:

- For owned in-state generation and PPAs with specified in-state sources, emissions information would be available from ARB's source-based reporting regulations.
- ARB would obtain emissions information regarding other specified sources from reports that those plants may submit voluntarily, or from power plant data submitted to federal agencies.
- For procurements from unspecified sources, ARB would develop default emission factors and/or supplier-based emission factors, as detailed in Section V.C of this order.
- ARB may need to make certain adjustments to ensure that attributed emissions are accurate and that reported emission reductions are real, as discussed in Section V.A of this order.

To allow assessment of emissions due to electricity generated in California and exported from the state, retail providers would be required to report information regarding their wholesale power sales, including exports. Marketers would similarly be required to report information regarding their exports from California.

Multi-jurisdictional utilities would be required to report information for their operations that serve California and any service territories contiguous to their California Service areas. ARB would attribute GHG emissions to their California operations based on the proportional share of their electricity sales in California.

Lastly, marketers would be required to submit information regarding imports of electricity into California, which would be needed if a deliverer/first-seller approach is adopted.

IV. Definitions, Criteria for Establishing GHG Reporting and Tracking Protocols, and Covered Entities

A. Definitions

Most of the definitions recommended in the Joint Staff proposal are not disputed by parties. We make several changes to the definitions in Attachment A in response to parties' comments and to provide greater clarity.

The California Municipal Utilities Association (CMUA) believes that the Staff report would expand the definition of "leakage" beyond that intended by AB 32 and improperly uses it within the Staff's definition of "contract shuffling." CMUA points out that AB 32 defines "leakage" as "a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state." We address CMUA's concerns regarding the Joint Staff's proposal regarding contract shuffling in Section V.A. below. We do not adopt the Staff's proposed definition of "leakage," since that term is defined in AB 32. Nor do we see a need to adopt a definition of the term "contract shuffling," since that term is not used in Attachment A.

The Division of Ratepayer Advocates (DRA) recommends that the definitions for "emission factor" be expanded to include all GHG emissions because, in DRA's opinion, AB 32 requires that all retail electricity providers measure GHG emissions related to their consumers' electricity consumption, and because Section 38505(g) defines GHG to include more gases than just carbon dioxide (CO_2). DRA is correct that AB 32 defines GHGs to include six gases: CO_2, methane, nitrous oxide, sulfur hexafluoride, hydrofluorocarbons, and perfluorocarbons. ARB will assign emission factors that reflect all six gases. While we clarify the definition of emission factors in Attachment A, we see no need to list the six gases in this definition.

For clarity regarding reporting requirements, we add certain definitions of terms that are used in Attachment A. Specifically, we define the Northwest geographic region to include Washington, Oregon, Idaho, and Montana, plus British Columbia. The Southwest region includes Arizona, Nevada, Utah, Colorado, and western New Mexico.

We also delete certain definitions that were in the Joint Staff proposal, but which are not needed in the Protocol recommended in Attachment A.

B. Covered Entities

The Joint Staff recommends that all retail providers of electricity in California be required to report under the recommended protocol. This encompasses all IOUs, ESPs, CCAs, POUs, and WAPA. As pointed out by the National Resources Defense Council and Union of Concerned Scientists (NRDC/UCS), DWR procures electricity to meet the needs of the State's water projects, but was not covered in the Joint Staff's proposal. Section 38530(b) requires that any reporting system adopted by ARB account for all electricity consumed in the State. The reporting Protocol that we recommend would require that DWR, as well as any other state agencies that generate or procure power to meet their electricity needs, report using the Retail Provider Reporting Protocol in Attachment A.

Several parties recommend that marketers be required to report information regarding power that they import into California. We agree that such a reporting requirement would be helpful, particularly if a deliverer/first-seller regulatory approach is adopted. In addition, marketers should be required to report information regarding power that they export from California. These reporting requirements are specified in the Marketers Reporting Protocol in Attachment A.

V. Attributing GHG Emissions to Various Sources of Electricity

For purposes of reporting GHG emissions, the Joint Staff explains that the sources of power used to meet retail load fall into two categories: power that can be tracked to a specific facility (specified sources) and power that can only be tracked to a mix of power plants at one of various geographic levels (unspecified sources).

In order to assign responsibility for GHG emissions to retail providers, the appropriate emissions factor of each source of power must be determined. This emission factor multiplied by the amount of power generated to deliver the power received from the source will yield the gross amount of emissions to be attributed to the retail provider, which must be adjusted for wholesale sales to other entities located within California. For specified sources, the plant-specific emission factor will be established by ARB based either on its own source-based reporting requirements or on data filed with the United States Environmental Protection Agency (EPA) or the Energy Information Agency (EIA). Suppliers that own their own generation resources may also obtain supplier-specific emission factors from ARB. For unspecified sources, estimated default emissions factors must be established.

A. AB 32 Requires Accurate Reporting and Real Emissions Reductions that Are Enforceable by ARB

AB 32 requires ARB to adopt, on or before January 1, 2008, regulations to govern the reporting and verification of statewide greenhouse gas emissions and to monitor and enforce compliance with this program. (Section 38530 (a).) The reporting system adopted by ARB will be used to ensure that the identified GHG reductions are "real, permanent, quantifiable, verifiable, and enforceable" by ARB. (Section 38562(d)(1).) The reporting and tracking system is central to determining individual entities' compliance with AB 32 and ensuring that the overall goals of AB 32 are achieved.

Retail providers balance a variety of objectives when procuring electricity. In addition to accommodating the variability of electricity demand that occurs from hour to hour, retail providers must factor in price volatility of underlying fuel sources, reliability of power sources, various Public Utilities Commission and Energy Commission program requirements (including Renewable Portfolio Standard (RPS), energy efficiency, and resource adequacy requirements), and general market volatility. As a result, retail providers use a variety of complex commercial arrangements to procure power.

As Staff notes, these complex arrangements may make it difficult to determine the true effect that a procurement choice can have on a retail provider's GHG emissions. With the exception of source-specific contracts, electricity can be resold and repackaged multiple times before a retail provider purchases it. Even with a source-specific contract, other power may be substituted should the need arise. Such transactions make it difficult to track the electricity to its original source. Therefore, default emission factors must be established based on analysis of sources in a region.

1. Staff's Proposal to Ensure Real GHG Emission Reductions

Staff is concerned that, with the advent of GHG regulation to meet AB 32 requirements, a retail provider may modify its PPAs or purchases from CAISO markets and report its power acquisitions in a manner that would make it appear that the retail provider has reduced its GHG emissions when, in reality, the same amount of GHG emissions is occurring as before.[2] In its report, Staff provides an example, as follows. A California retail provider that has an ownership share in an out-of-state high GHG-emitting generating facility could sell that power to an out-of-state entity which, in return, sells to the California retail provider the same amount of power but obstensibly from a lower GHG-emitting source. If only the purchase from the out-of-state entity is reported, it could appear that the California retail provider has reduced GHG emissions. However, in reality, the same amount of GHG would be emitted into the atmosphere.

Staff reports that there is sufficient relatively low-GHG generation (including from natural gas-fired plants) available outside of California such that, if such contractual power swap arrangements were treated as reducing the California retail provider's GHG emissions, California retail providers could be deemed to largely meet the statutory GHG reduction targets but with no reductions in the total GHG emissions due to electricity generation in the Western Electricity Coordinating Council (WECC).

The Joint Staff recommends that conditions be imposed on the recognition of facility-specific purchases for GHG accounting purposes to ensure that the power purchase truly induces generation from the specified plant. The Joint Staff explains that one acceptable condition may be the existence of a long-standing contractual relationship between the retail provider and a specified plant. At the same time, the Joint Staff cautions that new contracts for

---

[2] Joint Staff refers to this concern as "contract shuffling."

existing low- or zero-GHG plants are unlikely to yield real reductions in GHG emissions, commenting that "there is little reason to believe that an agreement between a retail provider and an existing plant will induce generation that would not have occurred anyway." Staff recognizes that any new plants owned or partially-owned by a retail provider should be viewed as being used to meet the retail provider's load. The new power plants will reduce overall demand for existing generation sources and, if the new power plant has lower GHG emissions than the previous source the retail provider utilized, a real reduction in GHG emissions will result. The Joint Staff also suggests that a long-term PPA signed between a retail provider and a developer prior to a plant's construction would be sufficient to demonstrate a causal link between the retail provider and the addition of the specified new capacity.

2. Positions of the Parties

Several parties object to the Joint Staff's proposal to restrict the manner in which emission factors would be attributed to power that retail providers report as being received from specified sources.

Several parties contend that the Joint Staff's proposed conditions regarding the treatment of emissions for power received from specified resources are not consistent with AB 32. In these parties' opinion, the intent of AB 32 was to reduce the carbon footprint of electricity consumed in California. They recognize that the intent of AB 32 is to mandate reductions in GHG emissions, but they argue that AB 32 does not support the Joint Staff's attempt to limit contract shuffling. In these parties' opinions, AB 32 does not purport to regulate GHG emissions from generation outside California if the electricity is not consumed in California. These parties argue that AB 32 prevents ARB from regulating out-of-state GHG emissions not caused by electricity consumed in California.

Parties also argue that it would be impermissible to regulate a California retail provider that sells a higher-emission resource and replaces it with an existing lower-emission resource. They assert that, as a state law, AB 32 cannot and should not affect the carbon reduction strategies of other states.

Several parties interpret the Joint Staff proposal as an attempt to disapprove or prohibit certain contracts. They interpret the Staff reference to limiting "claims" to existing low- and zero-GHG resources as a proposal to restrict their ability to enter into contracts with existing resources.

Parties argue that limiting facility-specific contracts would be contrary to criteria proposed by the Joint Staff. In particular, they assert that the Joint Staff's limits would have the unintended consequence of preventing California utilities from seeking and procuring existing renewable resources outside California.

CMUA and Morgan Stanley Capital Group Inc. (Morgan Stanley) argue that contract shuffling is not a large concern because of Senate Bill (SB) 1368 and other states' RPS goals. These parties contend that SB 1368 places significant restrictions on the procurement of unspecified resources to meet a retail provider's load.

3. Discussion

There are several potential types of contractual arrangements that could be used to show "paper" emission reductions, but which would not actually reduce GHG emissions. A California retail provider could sell power from its owned high-GHG generation facility to an out-of-state entity and simultaneously purchase power from a lower-GHG specified source, or from an unspecified source with a lower default emission factor. If the nature of such a contract shuffle is not recognized, ARB may apply the lower emission factor associated with the lower GHG purchase. It would appear to ARB that the retail provider had reduced its GHG emissions but, in reality, the high-GHG power plant would still be operating, making it unlikely that the total amount of GHG emissions within the region had been reduced. Alternatively, a California retail provider that usually purchases power from one source (specified or unspecified) could buy power instead from another existing source with a lower GHG emission factor, thus appearing to reduce its GHG emissions. However, in reality, total GHG emissions from both sources may remain at previous levels, with no real reduction in GHG emissions.

We agree with Staff that, through selling power from their high-GHG facilities or PPAs and replacing that power with existing low-GHG resources that would have operated anyway, California retail providers could attempt to receive credit for GHG reductions that are not real, as indicated by the above examples.

In their comments, several parties argue that AB 32 does not provide any authority to deal with the problems that the Joint Staff identify as contract shuffling. One of the arguments made is that contract shuffling is not necessarily "leakage" as defined in the statute. (Section 38505(i).) However, while minimizing leakage is one of the goals of the statute (Section 38562(b)(8)), the statute also requires ARB to ensure that the "greenhouse gas emission reductions achieved are real, permanent, quantifiable, verifiable, and enforceable" by ARB. (Section 38562(d)(1).) We propose that ARB adopt conditions that would prevent the attribution to retail providers of GHG emission reductions that are not real. Accordingly, such rules are within the scope of the statutory authority.

Several parties object to the Joint Staff report's concept of rejecting "claims" to specified sources. We think that the language concerning "claims" used in the Joint Staff report caused unnecessary confusion and accordingly we do not use this terminology in the proposed rules. The question we are dealing with here is whether a shift in the reported source of power would result in real emission reductions. If not, the retail provider should not get credit for illusory emission reductions.

While the Southern California Public Power Authority (SCPPA) raises such a concern in its comments, the rules we recommend to ARB would not cause any quantity of electricity to go unreported. Nor would they regulate out-of-state facilities selling electricity for consumption outside of California, as claimed by CMUA. Rather, these rules would specify the level of emissions that ARB would attribute to power obtained by a California retail provider in a manner that would ensure that any identified GHG reductions are real, as required by AB 32.

The recommended reporting rules would not prohibit parties from entering into contracts for the supply of electricity that they are otherwise permitted to enter into, a concern raised by the Los Angeles Department of Water and Power (LADWP). What these rules would establish is the level of GHG emissions that would be attributed to electricity procured pursuant to reported contractual relationships. To avoid the mistaken identification of GHG reductions that are not real, in some instances these rules would require that the level of emissions attributed to certain power for the purpose of GHG accounting be different than the level of GHG emissions that occurs from the source specified in the contract.

Some parties object to a suggestion in the Joint Staff report that certain contract shuffling problems might be dealt with by treating some purchases from specified in-state generating resources differently than purchases from specified out-of-state resources. We agree with these commenters that that suggestion should not be pursued further.

The methods that we recommend to ARB for attributing GHG emissions related to the purchase of power from existing specified sources and the sale of power generated by owned power plants would allow accurate tracking of GHG emissions and avoid the calculation and attribution of GHG reductions that are not real. While these recommendations are summarized here, they are discussed in more detail in Sections V.B.2 and V.D.1 of this order, with the recommended reporting and tracking protocol set forth in Attachment A.

First, we recommend that ARB attribute emissions to generation from owned power plants based on the ownership share of the reporting entity unless the retail provider demonstrates that (a) its proportional ownership share of the plant's output could not be delivered to the retail provider during the hours in which it was sold, or that (b) the retail provider did not need the power. If such a showing (described in more detail in Section V.D.2) is made, ARB would attribute emissions to the retail provider's share of power sold from the plant (either by the reporting entity or by the plant operator on the reporting entity's behalf) based on the emission attributes of the plant, thus removing those emissions from the retail provider's responsibility. Otherwise, ARB would attribute emissions to the sale using a default emission factor (described in Section V.C of this order) based on the average emission factor of the retail provider's sources that are available for unspecified sales. This recommendation would apply only to the portion of the sale that exceeds ten percent of the retail provider's proportional ownership share of the generation, in recognition of the fact that the retail provider may need some flexibility in receiving power from the power plant in order to meet its operational needs.

Similarly, we recommend that ARB attribute emissions associated with any purchases through new contracts with existing specified sources based on the default emission factor of the region in which the specified source is located.

We make these recommendations because it is our opinion that the high demand on all resources in the WECC region makes it unlikely that replacing power from high GHG-emitting resources with power from existing lower GHG-emitting resources would result in any operational change to the resources or lower total GHG emissions in the WECC region. Any GHG reductions that ARB may calculate as result of a retail provider replacing generation from a high GHG-emission source with lower GHG-emission purchases should require a convincing showing that real GHG emissions were achieved.

B. Specified Sources

A clear link between power delivered to a retail provider and a specific generating facility may exist if a retail provider owns or has an equity share in the facility or if it has a contract to purchase power from the facility. In some cases, certain utilities also receive allocations of power from federally-managed hydroelectric facilities. The GHG emissions associated with the delivered power can be determined with reasonable certainty based on these specified sources.

The Joint Staff describes that some contracts for purchasing power may describe a group of substantially identical resources at a single location as the source of power. We agree that, in that situation, it would be appropriate to treat the group of resources as a specified source for purposes of GHG accounting.

We address the determination of emission factors for purchases from different types of specified sources in turn.

1. Emission Factors for Owned or Partially-owned Specified Sources

In the Joint Staff report, Staff proposes that, for each wholly- or partially-owned generation source, the GHG emissions be based upon ARB-approved source data and, in the case of partially-owned generation, emissions should be allocated on the basis of the electricity taken. Staff proposes, however, that reporting entities be required to provide explanations whenever the share of generation taken deviates from the ownership share, with the apparent view that adjustments may be warranted if it appears that the retail provider engaged in a form of contract shuffling in an attempt to reduce its GHG emissions responsibility.

LADWP seeks clarification on the appropriate emission factor for coal-based generation sources. As described above, ARB plans to establish emission factors for each wholly- or partially-owned generation source. We encourage LADWP to address its concerns through the appropriate ARB workgroup.

SCPPA objects to the use of ownership shares in calculating the GHG emissions to be attributed to a retail provider that owns only a portion of a particular generating facility, stating that the attribution of emissions should be on the basis of actual deliveries. For reasons described in Section V.A., we recommend that ARB initially attribute emissions for owned and partially-owned power plants proportional to an entity's ownership share. As detailed in Section V.D, most of the sale of power from the power plant, either by the retail provider or by the plant operator on behalf of the retail provider, would be assigned a default emission factor for GHG accounting purposes unless the retail provider demonstrates that the power from the power plant could not be delivered to the retail provider at the time it was sold, or was not needed. With such a demonstration, the emissions associated with the generating facility would be attributed to the sale and would no longer be the responsibility of the reporting retail provider. Thus, the proposed rule we recommend to ARB, taken as a whole, would not automatically result in a retail provider being responsible for all of the GHG emissions associated with its ownership share of a plant. However, the requirement that retail providers provide an explanation does permit ARB to act in particular instances to prevent the reporting of reductions in GHG emissions that are not real. We note that, if a reporting retail provider sells its ownership share or the power plant does not operate, the retail provider would no longer be responsible for emissions from the power plant.

No party raised concerns with Staff's recommendation that ARB establish GHG emission factors for owned and partially-owned generation. It is our understanding that ARB will determine the emission factors for owned and partially-owned generation based on either its source-based reporting protocol or data that generators are required to file with EPA or EIA.

2. Emission Factors for Purchases from Specified Sources

For most power purchased from specified sources or obtained through exchange agreements from specified sources,[3] ARB will develop emission factors using information provided by in-state sources under ARB's source-based reporting requirements or, for out-of-state sources, from voluntary reporting by

[3] We recommend that power obtained or delivered through exchange agreements be treated as a purchase or sale, respectively, for purposes of GHG accounting.

those facilities or from EIA and EPA data. We address the appropriate emission factors for attribution to purchases from various types of specified sources.

a) New Contracts with Existing Specified Sources

As described in Section V.A, in our opinion it is unlikely that new contracts with existing generation sources would produce real reductions in GHG emissions, since most, if not all, of existing power plants would run the same regardless of any new contract. Therefore, we recommend that ARB attribute emissions for purchases from specified sources based on emission factors of the specified source only if (a) the purchase is made through a PPA that was in effect prior to January 1, 2008 and either is still in effect or has been renewed without interruption, or (b) the purchase is made through a PPA from a power plant that became operational on or after January 1, 2008.

b) Null Power from Renewable Resources

The term "null power" refers to electricity generated from a renewable resource for which the renewable and environment attributes have been sold to another party. The null power no longer has the emission attribute of a renewable resource. If both the retail provider purchasing the null power and the party purchasing the renewable attributes could report the low or zero-GHG emission characteristic of the renewable power, the GHG characteristics would be double counted.

Center for Resource Solutions (CRS) proposes that null power be assigned system average emission characteristics, to avoid double counting. Similarly, the Sacramento Municipal Utility District (SMUD) proposes that null power be assigned a default emission factor for the region in which the null power is generated.

Southern California Edison Company suggests instead that the emission factor of the renewable resource be used, regardless of whether the Renewable Energy Credits haven been sold.

We agree with CRS and SMUD that an emission factor must be established for null power to prevent double counting, and recommend that ARB use the default emission factor for the region in which the null power is generated.

c) Firming Power for Renewable Resources

Many contracts for the purchase of intermittent resources such as wind and solar contain provisions that provide for the use of non-renewable resources to "firm" the power to meet the energy profile needs of retail providers. SMUD recommends that the non-renewable power used to firm intermittent renewable resources be assigned the carbon attribute of the associated renewable resource. SMUD states that this treatment would be consistent with how both Commissions have implemented the emission performance standard.

We agree with SMUD that firming power for intermittent renewable resource should be treated in the same manner as both Commissions treated firming resources in implementing the emission performance standard. In D.07-01-039, we limited the amount of substitute energy purchases from unspecified sources such that the total purchase under a new renewable contract cannot exceed the total expected contracted-for output of the specified renewable power plant over the life of the contract. For purposes of GHG reporting, we recommend similarly that, if the total purchase under a renewable power contract is limited contractually to the total expected output of the specified renewable power plant to be sold to the retail provider over the life of the contract, firming power should be attributed the same emission characteristics as the contracted renewable power plant and need not be reported separately.

d) Substitute Power

Contracts for power from a specified source may be structured such that the seller will fill in, or "firm" power from the specified plant with power from unspecified sources during planned and unplanned outages, start-ups, ramp rates, and other operating conditions that limit the plant's output. SMUD requests that substitute power provided under such contracts be attributed the emission factor of the contracted-for facility.

In adopting the emission performance standard, we permitted substitute energy purchases up to 15 percent of the forecasted energy production of the specified power plant over the term of the contract, provided that the contract only permits the seller to purchase system energy for substitute power. We recommend that ARB attribute the emission factor of the contracted-for facility to substitute power, up to 15 percent of the energy delivered, consistent with the manner in which we implemented the emission performance standard. If substitute power comprises more than 15 percent of the energy delivered under the contract, all substitute power should have emissions attributed according to the source of the substitute power, using the default emission factors described in Section V.C.2 of this order.

C. Unspecified Sources

The Joint Staff recommends that default emission factors be used for purchases from CAISO and for purchases from other unspecified sources. We address each type of unspecified source in turn.

1. Emissions Factors for Power from CAISO Markets

The existing CAISO real-time market is a power pool, for which a link between a specific seller and a specific buyer does not exist. In the forthcoming

CAISO integrated forward market, most generators providing power to retail providers in the CAISO territory will have to bid into the market, even sources owned by or under contract to the retail providers. The emission factor discussed in this section for the Integrated Forward Market would apply only to power purchased that is not under contract with specified counterparties.

The default emission factor that Staff recommends for real-time purchases from the CAISO would be based on the emissions from hydro and natural gas units that can be ramped quickly. The Joint Staff report recommends a split of 90 percent gas and 10 percent hydro, resulting in a default factor of 900 lbs CO_2e/MWh. For the CAISO's Integrated Forward Market, the Joint Staff report expects that the market will include bids from all fuel sources but recommends a default emission factor of 1,000 lbs CO_2e/MWh, based on an assumption that natural gas will be the principal marginal resource.

Several parties urge adoption of a single default emission factor for the CAISO real-time and forward markets. Parties believe that different emission factors for the different pools would give market participants incentives and opportunities to enter into transactions that would undermine the efficient operation of electricity markets and would reduce the accuracy of these emission rates over time. In its opening comments, the CAISO advocated that the default emission factor for the two markets should be the emission factor (1,100 lbs/MWh) established by both Commissions for determining compliance of long-term contracts with the emission performance standard required in SB 1368. In reply comments, the CAISO, upon further reflection, acknowledges that the emission factor adopted to determine compliance with an emission performance standard is not equivalent to a market average emission factor that is needed for GHG reporting purposes. It now recommends that the

Commissions adopt the same emission factor for the real-time market and the Integrated Forward Market when it becomes operational. The CAISO recommends that the emission factor be between 1,000 and 1,100 lbs $C0_2e$/MWh.

We agree with the CAISO and recommend the emission factor of 1,000 lbs CO_2e/MWh for the CAISO real-time market and the Integrated Forward Market when it begins operations.

2. Emission Factors for Purchases from Other Unspecified Sources

Power from unspecified sources, whether purchased or obtained through an exchange agreement, may be obtained from companies that sell power primarily from their own facilities. Power may also be obtained from companies that market power from a mix of affiliated generating companies and/or from other market participants. This power usually cannot be attributed to a specific power plant or fleet of power plants and, thus, would be considered power from unspecified sources. Power may also be obtained from marketers that purchase power from a variety of generators and then resell the power either directly to retail providers or indirectly via other markets or brokers. Similarly, this power cannot be tracked to a specified source.

Due to the complexity of tracking purchases from marketers back to generation sources, the Joint Staff recommends that regional default emission factors be determined for purchases from unspecified sources in California, the Pacific Northwest, and the Southwest.

a) California

The Joint Staff recommends that power from in-state unspecified sources be assigned the average 2005 emission factor for all California natural gas units.

Staff reports the rounded emission factor to be 1,000 lbs CO_2e/MWh. No one objected to this number, and we recommend it to ARB.

b) Southwest and Pacific Northwest

The Joint Staff recommends that default emission factors for power obtained from unspecified out-of-state sources be calculated for the Southwest and Pacific Northwest regions by first removing from the calculation all power purchased from specified sources (whether purchased by California entities or by entities in other states). A marginal method then would be used to calculate a regional average emission factor based on the historical and future probable dispatch patterns of the region. An Energy Commission Staff paper[4] describes this method, which allocates unspecified resources based on a marginal generation analysis for the Southwest and on a hybrid method of marginal analysis and sales assessment for the Northwest. This approach reflects the increasing role of natural gas as a marginal resource, while viewing Northwest hydro as a marginal resource for Northwest sales.

The Joint Staff report concludes that power from unspecified sources in the Southwest is 90 percent natural gas and 10 percent coal, with a weighted average emission factor of 1,075 lbs CO_2e/MWh. Based on its hybrid analysis, the Joint Staff report characterizes power from unspecified sources in the Northwest as 66 percent hydro and 22 percent natural gas, with small amounts of coal, nuclear, and renewables. On that basis, the Joint Staff obtained a Northwest default emissions factor of 419 lbs CO_2e/MWh.

[4] Alvarado, Al and Karen Griffin, "Revised Methodology to Estimate the Generator Resource Mix of California Electricity Imports," CEC-700-2007-007, March 2007.

Several parties dispute the default emission factor that the Joint Staff recommends for unspecified purchases from the Northwest. Some of these parties object that "unintended consequences" would occur because the Southwest default emission factor would be more than twice the size of the default emission factor that the Joint Staff recommends for the Northwest. These parties believe that this difference would provide incentives for parties to enter into transactions to hide high-emission sources located in the Southwest by moving power through California to the Northwest and then back into California. They suggest further that sellers could hide high-emission sources located in the Northwest by selling power from such sources into the Northwest power pool, with the power then resold as pool power, which would be attributed the default emission factor for the Northwest. In their view, either situation would reduce the accuracy of reported GHG emissions associated with serving California load and could also increase congestion on an already-constrained transmission system.

The Oregon Public Utility Commission and the Oregon Department of Energy (Oregon) and the State of Washington, Department of Community, Trade and Economic Development (Washington) express concerns that the methodology used in the Joint Staff proposal to develop a default emission factor for unspecified sources in the Northwest is inconsistent with the methodology currently used in Oregon and Washington. They contend, specifically, that the use of inconsistent methodologies in the Northwest and California would result in double-counting of hydropower. Oregon and Washington assert that hydropower in their states is used primarily to serve local or regional loads and that thermal power (coal and gas) is exported to serve load in California. In 2005, Oregon and Washington determined that the emission factor for the "net system mix" of electricity available for export from their region was 1,062 lbs CO_2e/MWh. In contrast, the Joint Staff methodology would indicate that over 66 percent of the power from unspecified Northwest sources imported into California are low-emission resources, resulting in an emission factor of 419 lbs CO_2e/MWh.

Oregon and Washington want to work with California to develop mutually-agreeable accounting methodologies for Northwest default emission factors. In the meantime, they urge the Commissions to reject the Joint Staff proposal in this regard and to adopt a default emission factor for the Northwest based on the accounting methodology currently employed by Oregon and Washington.

Several parties respond that the Commissions should not adopt the accounting methodologies proposed by Oregon and Washington for establishing a default emission factor for imports from the Northwest, although some encourage the states to develop a mutually-agreeable accounting methodology. At the same time, several parties favor the development of a default emission factor for the Northwest based on a marginal or dispatch-based approach. The Community Environmental Council and DRA propose interim Northwest default emission factors that are closer in value to the default emission factor that the Joint Staff proposes for the Southwest. CMUA, Pacific Gas and Electric Company (PG&E), and SCPPA argue that, regardless of the methodology chosen, a single approach should be used to calculate historical 1990 emissions and current entity-specific emissions, and in the adopted reporting protocol.

SCPPA argues that the Joint Staff's recommended method of basing the Northwest default factor, in part, on historical sales is not consistent with the "pure" marginal approach that the Joint Staff uses to calculate the default emission factor for the Southwest. SCPPA asserts that, if marginal economic dispatch modeling were used to calculate the Northwest default emission factor, this would indicate that the cheapest resources (hydro) would be used to serve native load in the Northwest and that more expensive resources (coal and gas) would be used to serve load in California. The resulting default emission factor would be larger than the Joint Staff recommends. SCPPA argues that this larger emission factor would eliminate incentives to hide higher-emission resources in the Southwest. SCPPA contends that Oregon, Washington, and California are each attempting to include non-firm hydro in the resource mix serving load in that state, which could be avoided by using SCPPA's proposal to base default emission factors on economic dispatch.

Calpine Corporation (Calpine) and NRDC/UCS urge adoption of higher default emission factors than those recommended by the Joint Staff, for both the Southwest and the Northwest, in order to encourage retail providers to use less power from unspecified sources and to encourage retail providers to contract with low- and zero-emission resources. Calpine recommends that default emission factors should represent emissions from the highest emitting unit in the region. NRDC/UCS recommend that the emission factor for all natural gas plants be set at the emission factor for the least efficient natural gas plant (1,640 lbs CO_2e/Mwh).

Several parties recommend that default emission factors not be developed or used. Some of the parties contend that source-based GHG regulation and reporting are preferable. Several assert that a regional tracking system will be in place prior to the effective date of GHG restrictions pursuant to AB 32, thus eliminating the need for default emission factors.

PG&E contends that insufficient information and data are presented in the Joint Staff's proposal to determine whether the proposed default emission factors are accurate, fair and verifiable. PG&E recommends that the reporting protocol be adopted without specific default emission factors and further workshops be scheduled to discuss calculation of emission factors.

We are not persuaded by the concerns that parties raise about Staff's approach to calculating the Northwest and Southwest default emission factors. We are firmly committed to accurate reporting that reflects actual regional variations in emission factors. Establishing an artificially high default emission factor would not be consistent with our goal of accurate reporting.

We are not convinced by parties' assertion that entities will arbitrage regional variations in emission factors. With the many factors that must be balanced by retail providers when making procurement decisions, it seems unlikely that a differential in regional emission factors would induce retail providers to engage in extra trades to "launder" high GHG-emission resources.

No party disputes the Joint Staff's conclusion that the weighted average emissions factor in the Southwest is 1,075 lbs CO_2e/MWh. We recommend that ARB adopt this emission factor as the default emission factor for sales from unspecified sources in the Southwest.

We agree with Oregon and Washington that the default emission factor used for purchases from the Northwest should accurately reflect the resources that Northwest companies use to serve their load. We are not persuaded that the marginal resources in the Northwest are always fossil fuel plants, as some parties argue. The unique characteristics of hydroelectric generation, particularly the limited ability to store water, mean that hydroelectric generation is often sold as a marginal resource by regional power administrations. At the same time, we agree that Staff did not account adequately for the amount of coal used by marketers that sell power to California retail providers. As detailed in Attachment B, the Staff's proposed methodology has been modified to attribute a default emission factor of 1,062 lbs CO_2e/MWh for imports from Northwest utilities, excluding British Columbia hydro. A different resource mix is applied to sales from Northwest marketers, since some own merchant coal and natural gas-fired generation in the region and purchase surplus electricity from the Bonneville Power Administration for resale to California. We do not modify the Staff's other assumptions, including the assumption that 23 percent of California's unspecified imports come from British Columbia hydroelectric sources. The revised Northwest default emission factor that we recommend to ARB is 714 lbs CO_2e/MWh.

c) Asset-Owning or Controlling Entities

The Joint Staff suggests that separate GHG emission factors may be appropriate for purchases from generators that sell power on an unspecified basis from their own fleets of generating units. Asset-owning or controlling sellers could document their sources of power to avoid attribution of a regional or other default emission factor. We agree that entities that own or control generating assets should be allowed to request that ARB develop and apply a supplier-specific emission factor for their sales from unspecified sources.

d) When to Calculate Default Emission Factors

The Joint Staff report describes that default emission factors could be estimated after a reporting period based on factors such as hydro availability and weather. Another option is to calculate ex ante emission factors that could be fixed at the start of a reporting period. The Joint Staff recommends that default emission factors be calculated on an ex ante basis to provide greater market certainty to retail providers.

Several parties support the Joint Staff recommendation in this regard. However, NRDC/UCS argue that ex post calculation of emission factors would provide a higher level of precision. In their view, if emissions factor were calculated ex post on an annual basis, retail providers would know the emissions factors established for the previous year and could use those emissions factors for planning purposes. They assert that, in most circumstances, emissions factors would be unlikely to deviate significantly from one year to the next. As a compromise, NRDC/UCS suggest that, to provide greater market certainty for retail providers, a hybrid approach could establish, on an ex ante basis, a range for allowable emission factors for each region. The specific emission factor would then be determined ex post on an annual basis, but would be limited by the adopted range.

We agree with Staff that default emission factors should be calculated on an ex ante basis to provide greater market certainty to retail providers.

e) Updating Default Emission Factors

The Joint Staff recommend that default emission factors be updated periodically, possibly every three years. Several parties urge more frequent updating of emissions factors. One party suggests that the frequency with which default emission factors should be updated be resolved after more of the structure of GHG regulation has been resolved.

We recommend that ARB update the default emission factors on annual basis, at least initially, so that ARB, the reporting entities, and other market participants can better understand the implications of the adopted GHG regulations.

D. Retail Providers' Wholesale Sales

AB 32 governs statewide GHG emissions, including electricity consumed in California (including imports), and in-state generation that is exported out of California. In a load-based approach, retail providers would be responsible for the GHG emissions incurred to meet their retail load and for power exported out of California. They would not be responsible for the GHG emissions associated with power they sell or deliver through exchange agreements to counterparties located within California. In a load-based approach, once a retail provider's own generation, power purchases, and related GHG emissions are known, GHG emissions must be attributed to the retail provider's wholesale sales and the emissions attributable to in-state sales must be deducted from the retail provider's emission responsibilities. The remaining GHG emissions represent the power used to serve the retail provider's in-state load and any sale of power that was exported from the state.

1. Sales from Specified Sources

Retail providers may make sales from specified sources or deliver power from specified sources through the terms of an exchange agreement. If delivered to a counterparty located in California, the corresponding emissions would be removed from the provider's GHG responsibility.

To adjust total emissions for sales and exchanges from specified sources, ARB would use source-specific emission factors, as described in Section V.B.1 above. However, an adjustment may be needed to the manner in which emissions are attributed to sales from owned or partially-owned power plants, to address concerns regarding contract shuffling, as discussed in Section V.A. To the extent that sales from an owned or partially-owned power plant amount to less than ten percent of the retail provider's proportional ownership-based share of the total net generation, we recommend that ARB attribute emissions based on the emission factor of the specified power plant.

Because of concerns about contract shuffling, we recommend that ARB require justification if sales from an owned or partially-owned power plant amount to more than ten percent of the retail provider's proportional ownership-based share of the total net generation. We recommend that, if the retail provider demonstrates either that the power could not be delivered to the retail provider during the hours in which it was sold or that the retail provider did not need the power during the hours in which it was sold because it had surplus power from its owned power plants and the specified plant was the marginal plant during the hours in which the power was sold, ARB attribute emissions to the power sold based on the emission factor of the power plant. Otherwise, ARB should use the default emission factor for sales from unspecified sources for the portion of sales in excess of ten percent of the retail provider's proportionate ownership-based share of the plant's total net generation.

2. Sales from Unspecified Sources

The Joint Staff report proposes what it calls an "adjusted all-in" methodology for the attribution of GHG emissions to a retail provider's sales from unspecified sources. The Staff method would remove sources reported as serving the retail provider's own native load from its resource mix and then would determine an average GHG emission factor for generation from the remaining owned assets and purchases. The retail provider's sales from unspecified sources would be assigned this average GHG emission factor. The Joint Staff suggest that retail providers be allowed to request that a more disaggregated calculation be performed if they believe that this averaging method does not reflect accurately the nature of their transactions. No parties commented on the Joint Staff's proposal to account for GHG emissions associated with sales from unspecified sources using the "adjusted all-in" method.

With some modifications, we adopt Staff's proposal to use the "adjusted all-in" method to calculate GHG emissions associated with retail providers' sales from unspecified sources. First, in addition to sources reported as serving native load, power that the retail provider sold or delivered pursuant to an exchange agreement from specified sources should be removed from the retail provider's resource mix before an average emission factor is calculated for power available for unspecified sales. Additionally, we limit and clarify the sources that a retail provider may claim as serving native load.

As described above, the retail providers' GHG emissions responsibilities are adjusted for sales to other entities in California. Sales of power to entities outside the state constitute exports, and emissions responsibilities should be attributed to the selling party, in this case the retail provider.

VI. Recommended Reporting Protocol

A. What Will Be Reported

In the Joint Staff's proposal, California retail providers would be required to report total GHG emissions from all power used to serve their load in California. That proposal would require that retail providers submit the total quantity of power generated and purchased separately for specified and unspecified sources, emission factors for specified sources, and wholesale sales. However, as described above in Section III, ARB intends to establish emission factors for all specified and unspecified sources. ARB will also determine the total GHG responsibility for each retail provider. As a result, the reporting protocol we adopt today reflects ARB's planned process.

We recommend that ARB require retail providers to report the source of all power used to serve load in California. For specified sources, retail providers would identify the amount of power received, associated transmission losses, and a unique ARB or EPA plant identification code. For partially-owned power plants, the proportional ownership share is required. For unspecified sources, retail providers would report the amount of power received, associated transmission losses, and the region that is the source of the power. Retail providers would also report wholesale sales by counterparty and by destination region (California, Northwest, and Southwest). Wholesale sales are also to be differentiated between sales from specified power plants and unspecified sales from the retail provider's pool of generated and purchased power. Aggregated wholesale sales would be reported by counterparty and by destination region. Wholesale sales should not reflect transmission losses, which are accounted for by the buyer.

As several parties suggest, we recommend that ARB adopt reporting requirements for 2008 that would facilitate consideration by ARB and the Commissions of the deliverer/first-seller type of GHG regulation. We recommend additional reporting requirements, which would direct marketers that either import power into or export power from California to report all such sales by counterparty, disaggregated by region as appropriate. Marketers would also be required to report any power wheeled through the state of California. Requiring reporting in this manner will provide necessary information for cross-checking and control totals, if the deliverer/first-seller approach is chosen for the electricity sector. If the deliverer/first-seller approach is not chosen, the additional reported information may still be helpful to ARB.

B. Submission Process

1. State Agency Responsibilities for Receiving and Maintaining Data

The Joint Staff proposes that ARB be the primary recipient of all GHG emission reports and that both Commissions receive simultaneous copies of all reports filed with ARB. We agree with Staff's recommendation.

2. Frequency of Reporting

The Joint Staff proposes that retail providers submit annual GHG reports. Most parties support this proposal. DRA wants quarterly reporting as a means to increase transparency. PG&E recommends that the frequency of reporting be consistent with the nature of the market and recommends that the appropriate frequency be determined after the market has been designed. We agree with Staff's suggestion and recommend that ARB require that retail providers and marketers submit annual reports.

3. Verification

Verification is vital to any credible tracking system. ARB proposes to use third-party certification for all reporting under AB 32, and is developing a training and certification program for third party auditors.

While the Joint Staff considers the development of verification rules to be within the ARB's responsibilities, some parties want the Commissions to address verification in more detail. Several parties note that verification would be very difficult for out-of-state operations. Others are concerned about the burden that a verification system might place on retail providers. Environmental Defense and DRA stress the importance of a strong compliance mechanism in an effective reporting and tracking system.

We agree that verification is a critical component to any mandatory GHG reporting mechanism. ARB is developing a verification process including requirements for third-party certifiers. We believe that ARB is in the best position to develop appropriate verification requirements, and we direct our Staff to work with ARB to address any unique verification requirements for the electricity sector.

4. Reporting Template

The Joint Staff proposal includes a reporting template. Several parties recommend clarifications and minor corrections to the template. The Alliance for Retail Markets (AREM) wants a streamlined reporting template for non-asset-owning retail providers.

As we have noted, the Joint Staff's proposal assumes that retail providers would report emission factors and total GHG emission responsibilities. With ARB's plan to develop emission factors itself, we modify the reporting template proposed by the Joint Staff to reflect ARB's planned reporting system. As a result, some of the recommended clarifications and minor corrections proposed by parties are moot.

The reporting requirements that we recommend to ARB are contained in Attachment A. Section 3.15 of Attachment A contains a sample reporting form that parties could use, subject to any modifications in the reporting requirements that ARB may adopt.

C. Reducing Reporting Burden

Some of the smaller retail providers believe that the Joint Staff reporting proposal should be modified to reduce the burden and costs on smaller retail providers of reporting GHG emissions. AREM and several POUs desire a web-based reporting system. Some of the smaller retail providers recommend that the Energy Commission work with ARB to reduce duplicative reporting of facility generation. CMUA encourages the Energy Commission, the Public Utilities Commission, and ARB to work toward a single, unified set of reporting requirements.

In modifying the reporting protocol to be consistent with ARB's planned reporting process, we have responded to parties' request for a streamlined reporting protocol that reduces the burden on reporting entities.

D. Review of Adopted Protocols

Staff recommends that reporting protocols implemented in 2008 be reviewed no later than 2011 so that they can be refined for the first compliance year in 2012.

We agree with Staff that a comprehensive review of the reporting protocol should be conducted prior to the first compliance year in 2012. The review should occur early enough to allow time to implement any revisions in 2011, so that parties may accommodate any revisions prior to the first year of compliance. We recommend that ARB undertake a review early enough to ensure that any revisions will be effective during the 2011 reporting year.

E. Reporting and Tracking under Deliverer/First-Seller Regulation

Many parties submit that the Joint Staff reporting proposal would need to be modified if a deliverer/first-seller structure is adopted. Some of these parties propose detailed modifications to the Joint Staff proposal to provide the reporting needed under a deliverer/first-seller structure. Most of the proposed changes would require that the first entity that sells power into California track and report the emissions associated with such sales.

We do not address the merits of the deliverer/first-seller approach today, but we recommend that ARB include requirements that wholesale marketers report any sales where the marketer is the first party to deliver power into California. This, combined with ARB's intention to require most generators to report source emissions directly to ARB, would provide much, if not all, of the additional information regarding GHG emissions that would be needed if the deliverer/first-seller approach is adopted. However, that approach still requires development. As a result, additional reporting changes may be necessary if the deliverer/first-seller approach is adopted.

F. Confidentiality

AREM requests that the reporting protocol include provisions to maintain the confidentiality of market-sensitive information and to avoid disclosure of detailed transaction data. AREM recommends that the reporting protocol include the "window of confidentiality concept" adopted by the Public Utilities Commission in D.06-06-066.

While we agree with AREM that the early release of market-sensitive information could adversely affect retail providers, we do not make recommendations to ARB regarding the extent to which the data reported to ARB should be treated confidentially. AREM should address its concerns about the release of market-sensitive information in the ARB process that is currently developing confidentiality requirements. In adopting final reporting regulations, ARB will determine what, if any, information will be treated confidentially.

VII. The Need for Regional Reporting and Tracking

Staff suggests that a comprehensive generation information system could be developed for the WECC region. A regional system would require that all (or most) states and provinces require the plants located in their areas to participate in the tracking system.

The Joint Staff report describes that a growing number of states either allow or require retail providers to designate the generation that serves their native load. Washington and Oregon have a tracking system in place, and several states are adding renewable portfolio standards, which mandate that renewable energy meet a designated portion of native load. The Joint Staff report recognizes that resources used to serve native load in another state should not be counted as sold to California retail providers. Staff proposes a pilot project with Oregon and Washington to help identify resources claimed by sellers to avoid double counting.

Adoption of GHG regulations in additional Western states would increase the importance of a regional reporting and tracking system. One particularly important development is the Memorandum of Understanding (MOU) to establish a regional GHG program for the Western states that are signatories. To date, the MOU has been signed by the governors of six Western states (California, Washington, Oregon, Arizona, New Mexico, and Utah) and the premier of British Columbia. Several federal climate change bills also have been proposed in Congress.

Many of the commenting parties urge the Commissions to move forward rapidly with the development of a regional reporting and tracking system. Some parties suggest that California take leadership, either working through the Western Governors Association or starting with the states that signed the MOU. The parties assert that a regional reporting and tracking system is the only way to produce a completely accurate "source-to-sink" accounting of GHG emissions attributed to electricity that serves California's retail load.

A few parties recommend that the Commissions not develop an interim reporting and tracking system, but instead wait until a regional tracking system is implemented. Other parties accept that an interim reporting system is needed in California, but want a regional solution to be in place prior to 2012, the first year that AB 32 GHG emission reduction requirements will be in force. Several parties suggest that concerns about contract shuffling and leakage can only be addressed by having a regional reporting and tracking system.

We support the call for a regional reporting and tracking system made by several parties in this proceeding. A regional solution to reporting and tracking would greatly increase the accuracy of GHG reporting in California. We urge ARB to lead a regional development effort.

While we support parties' recommendation that a regional solution be in place before January 1, 2012, AB 32 requires that ARB adopt reporting and verification regulations on or before January 1, 2008, and our recommendations support that statutory mandate. The reporting protocol we recommend would aid ARB and the reporting entities during the interim period until a regional reporting and tracking system can be developed and implemented. We recommend that ARB continue to refine our recommendations. Our recommended reporting protocol could be utilized for determining compliance, if a regional solution is not in place by January 1, 2012.

VIII. Reduced Comment Period

Pursuant to Section 311 of the Public Utilities Code and Rule 14.6(c)(9) of the Public Utilities Commission Rules of Practice and Procedure, the 30-day period for public review and comment is reduced. Parties may file comments no later than August 24, 2007 and reply comments no later than August 30, 2007. Public necessity requires that the comment period be reduced so that the Public

Utilities Commission and the Energy Commission can provide recommendations to ARB by mid-September, 2007 and so that ARB may consider these recommendations as it prepares its draft regulations for publication in early October. AB 32 requires that ARB adopt reporting regulations on or before January 1, 2008.

IX. Assignment of Proceeding

President Michael R. Peevey is the Assigned Commissioner in this proceeding, and Charlotte F. TerKeurst and Jonathan Lakritz are the assigned Administrative Law Judges in Phase 2 of this proceeding.

Findings of Fact

1. Some purchases of electricity cannot be traced to a specific generation source.
2. To attribute emissions to California retail providers for purchases of electricity that cannot be traced to a specific generation source, ARB will need to establish emission factors.
3. The Joint Staff's methodology to calculate emission factors for electricity purchased from unspecified sources, as modified by this order, is reasonable.
4. Emission factors for electricity purchased from unspecified sources should reflect the mix of power plants in the region from which the electricity is purchased.
5. The three default emission factors shown in Table 1 for electricity purchased in 2008 from unspecified sources in the Northwest, Southwest and California are reasonable.
6. The default emission factor shown in Table 1 for electricity anonymously purchased in 2008 through either the CAISO's real-time market or the Integrated Forward Market is reasonable.

7. The Protocol in Attachment A is a reasonable rule for reporting and tracking GHG emissions from the electricity sector.

8. In some situations, to ensure that only real GHG reductions are calculated for power transactions reported by California retail providers, ARB may need to attribute emissions to purchases of power by California retail providers that are different than the GHG emissions that occur from the source specified in the contract.

Conclusions of Law

1. Under AB 32, ARB has the authority to adopt conditions that would prevent the attribution to retail providers of GHG emission reductions that are not real.

2. AB 32 governs statewide GHG emissions, including electricity consumed in California (including imports) and in-state generation that is exported out of California.

INTERIM ORDER

Therefore, **IT IS ORDERED** that the California Public Utilities Commission recommends that the California Air Resources Board adopt the Proposed Electricity Sector Greenhouse Gas Reporting and Tracking Protocol contained in Attachment A to this order.

This order is effective today.

Dated ______________________________, at San Francisco, California.

INFORMATION REGARDING SERVICE

I have provided notification of filing to the electronic mail addresses on the attached service list (Attachment C).

Upon confirmation of this document's acceptance for filing, I will cause a Notice of Availability of the filed document to be served upon the service list to this proceeding by U.S. mail. The service list I will use to serve the Notice of Availability of the filed document is current as of today's date.

Dated August 15, 2007, at San Francisco, California.

/s/ ROSCELLA GONZALEZ
Roscella Gonzalez